ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

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Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22
Attachment B - AoR_CA	3	12/21/22

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability

- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).
3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

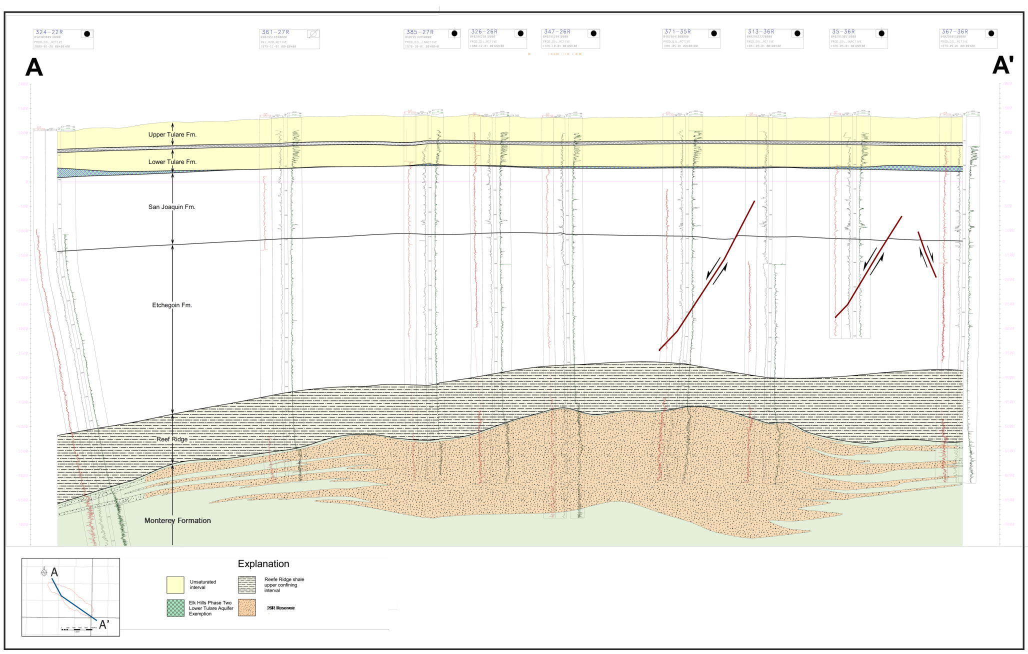
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



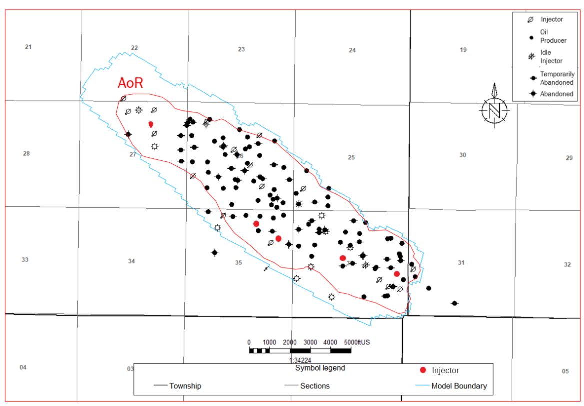
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (figure 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

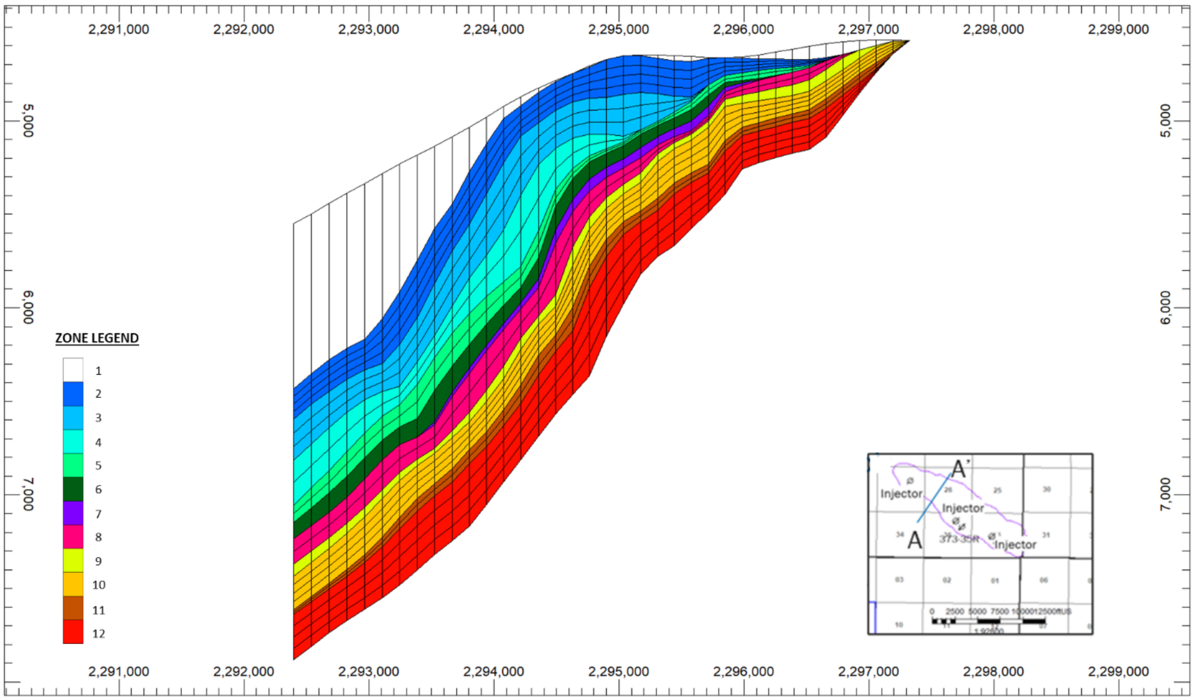
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir showing the 12 zones, and the 27 layers. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4) that is dependent on porosity and clay volume.

Figure 4: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

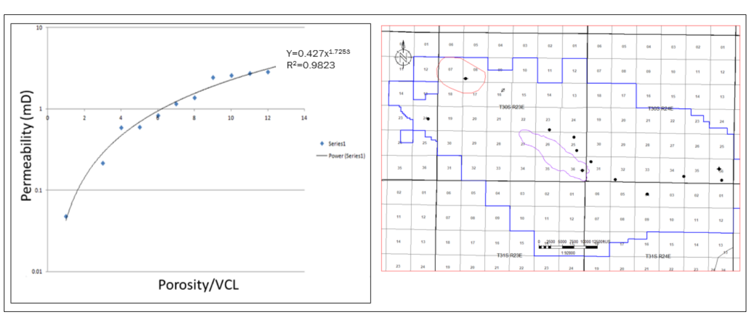


Figure 5: Monterey Formation 26R sands porosity and permeability distribution in the static model.

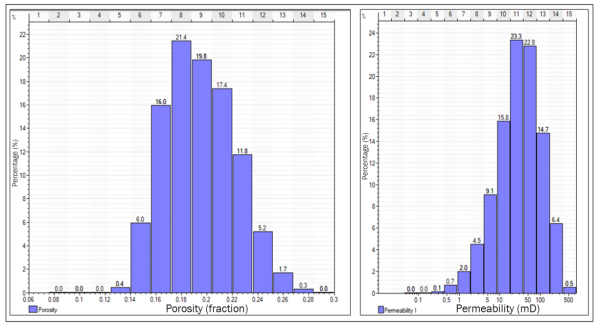
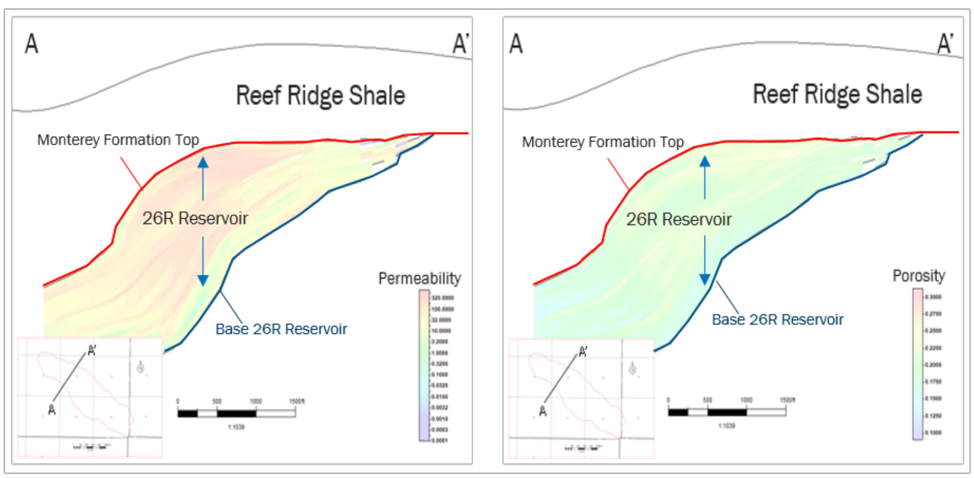


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 6: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

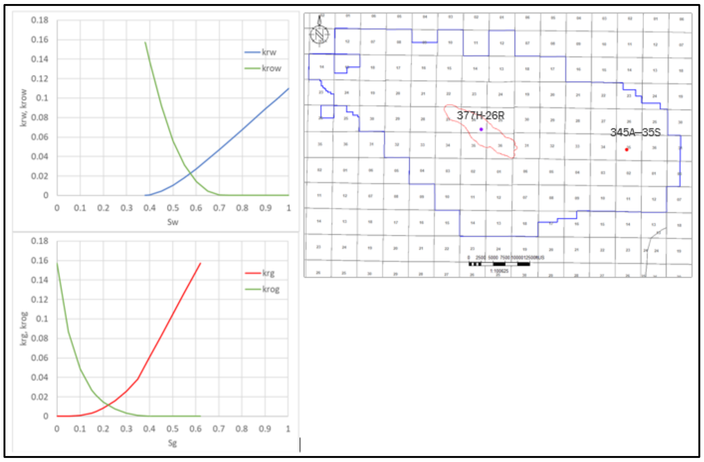
	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 7 shows the relative permeability curves used in the computational modeling.

Figure 7: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

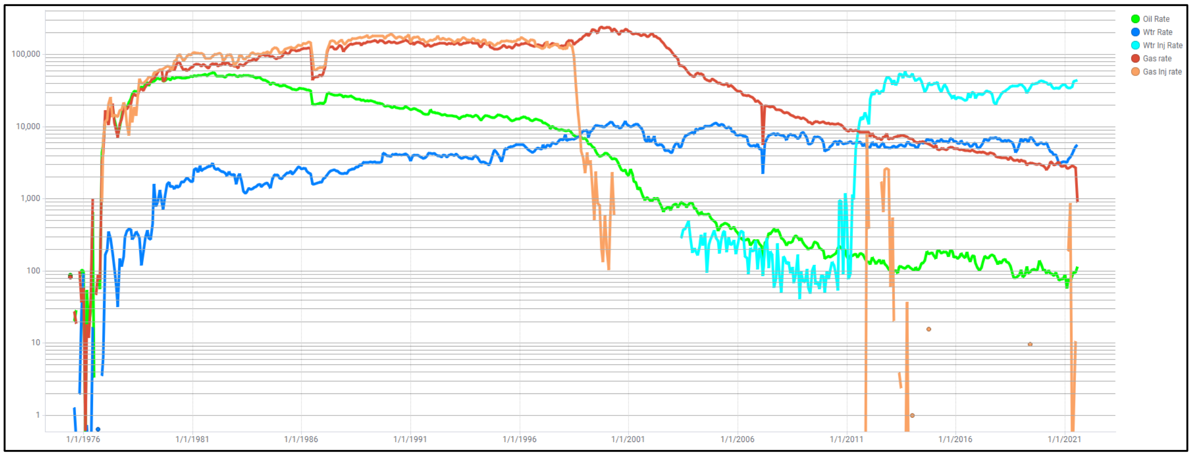
2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 8) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 8) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

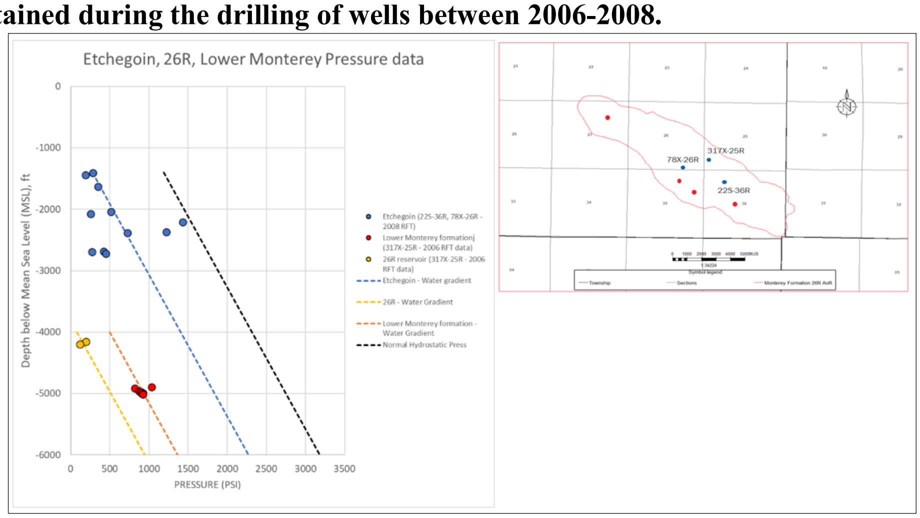
iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

Figure 8: Monterey Formation 26R production and injection data.



Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 9 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Figure 9 : Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	**Value or Range**	**Units**	**Corresponding Elevation (ft, below Mean Sea Level)**	**Data Source**
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	**Injection Well 1 373-35R**	**Injection Well 2 345C-36R**	**Injection Well 3 353XC-35R**	**Injection Well 4 363C-27R**
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	6121906 2290081	6126556 2289316	6121940 2290248	6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	6807 / 7086 7109 / 7426	6097 / 6101 7710 / 7720	6625 / 6810 8373 / 8545	6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	1/1/2025 9/1/2051	1/1/2025 9/1/2051	1/1/2025 9/1/2051	1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	**Injection Well 1 373-35R**	**Injection Well 2 345C-36R**	**Injection Well 3 353XC-35R**	**Injection Well 4 363C-27R**
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Proposed Carbon Dioxide Stream

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 tonnes per annum) with additional potential CO2 from the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the area. CTV expects the CO_2 stream to be sampled at the transfer point from the source and analyzed according to the analytical methods described in the QASP document and the Attachment C –Testing and Monitoring plan document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

For the purposes of Geochemical modeling, CO2 Plume modeling, and Well design, two major types of Injectate compositions were considered based on the source.

- Injectate 1: is a potential injectate stream composition from a Direct Air Capture (DAC) or a Pre-Combustion source (such as a blue hydrogen facility) or a Post-Combustion source (such as a gas fired power plant or steam generator).
- Injectate 2: is a potential injectate stream composition from a Biofuel Capture source (such as a Biodiesel plant) or an Oil & Gas Refinery.

The compositions for these two injectates are shown in Table 7, and are based on engineering design studies and literature.

Table 7 : Injectate compositions

Component	Injectate 1	Injectate 2
	Mass%	Mass%
CO	99.213%	99.884%
H2	0.051%	0.006%
N2	0.643%	0.001%
H2O	0.021%	0.000%
CO	0.029%	0.001%
Ar	0.031%	0.000%
O2	0.004%	0.000%
SO2+SO3	0.003%	0.000%
H2S	0.001%	0.014%
CH4	0.004%	0.039%
NOx	0.002%	0.000%
NH3	0.000%	0.000%
C2H6	0.000%	0.053%
Ethylene	0.000%	0.002%
Total	**100.00%**	**100.00%**

For geochemical and plume modeling scenarios, these injectate compositions were simplified to a 4-component system, shown in Table 8. The 4 component simplified compositions cover 99.9% by mass of Injectate 1 & 2 and cover particular impurities of concern (H2S and SO2). The estimated properties of the injectates at downhole conditions are specified in Table 9

Table 8: Simplified 4 component composition for Injectate 1 and Injectate 2

Injectate 1	
Component	**mass%**
CO2	99.213%
N2	0.643%
SO2+SO3	0.003%
H2S	0.001%

Injectate 2	
Component	**mass%**
CO2	99.884%
CH4	0.039%
C2H6	0.053%
H2S	0.014%

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This will be ensured by maintaining a water specification limit <25 lb/mmscf for the injectates, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate will be sampled and analyzed as part of the pre-operational testing, to confirm that it is consistent with the well design, Plume modeling and Geochemical modeling assumptions.

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO_2 injectate stream was assumed for the base case simulation studies. Additionally, scenarios were also run for the two injectates (Injectate 1 and Injectate 2) detailed in the "Proposed Carbon Dioxide Stream" section. Minimal difference in results was seen between the cases. Table 9 summarizes the expected CO_2 injectate properties at reservoir conditions over the life of the project.

Table 9: CO2 injectate properties at reservoir conditions

Injectate property	100% CO2	Injectate 1	Injectate 2
Viscosity, cp	0.019-0.044	0.019-0.043	0.019-0.045
Density, kg/m3	16.6-544.8	16.5-543.5	1.035-545.8
Salinity, ppm	NA	NA	NA
Compressibility factor, Z	0.97-0.59	0.97-0.59	0.97-0.59

The following maps (Figure 10) and cross-sections (Figure 11) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO_2 plume grows rapidly within the first 15 years of injection with majority of the CO_2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO_2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO_2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO_2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO_2 into the aqueous and oleic phases at the edge of the plume. The CO_2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO_2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 12 shows the average pore volume pressure vs time.

Figure 10: Plan view showing the plume development through time. Plume is at its greatest extent at 20 years post injection.

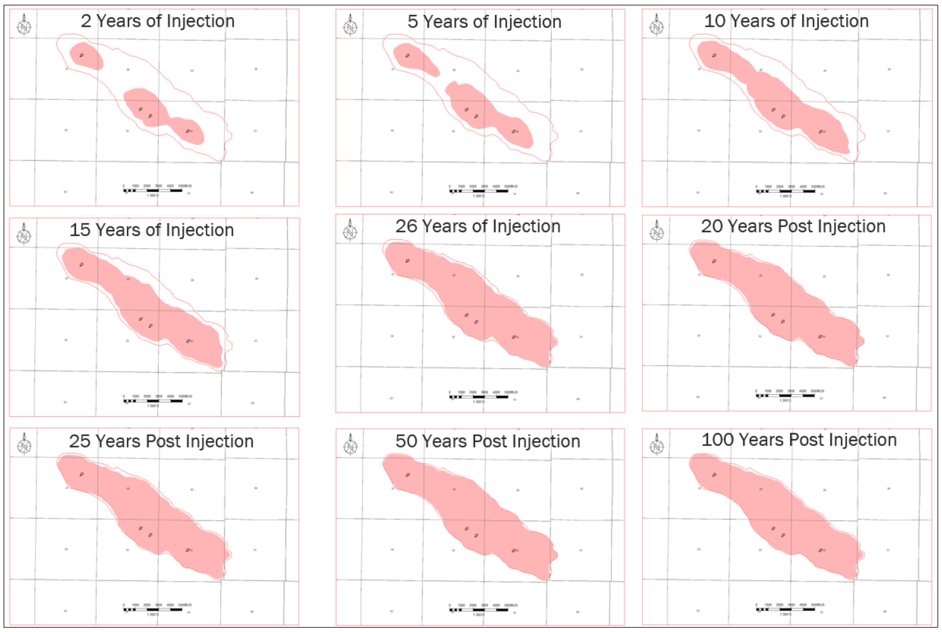


Figure 11: Cross-sections showing the plume development through varying times through the project.

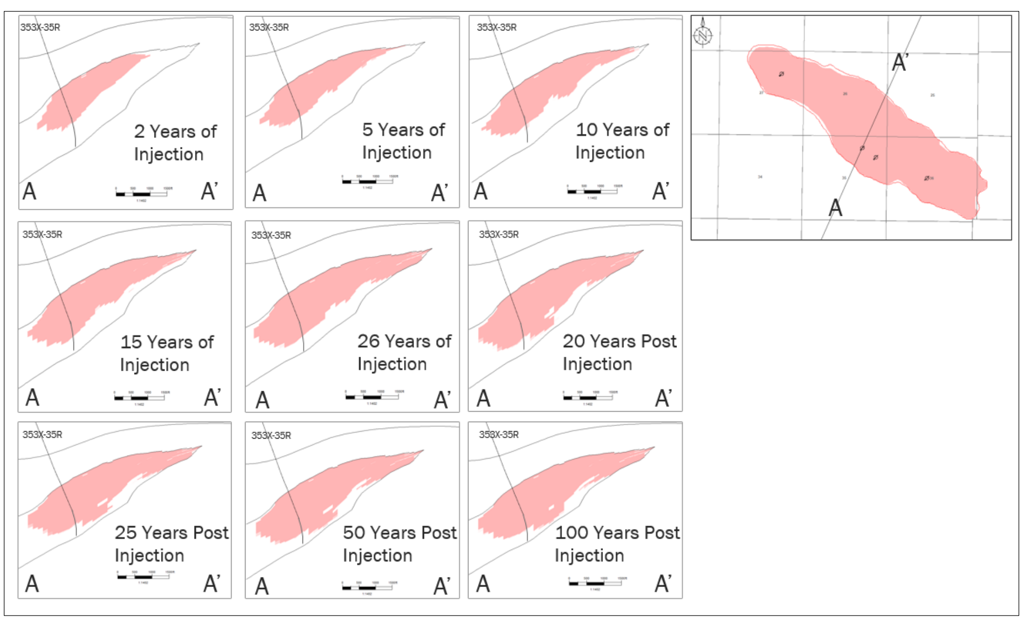
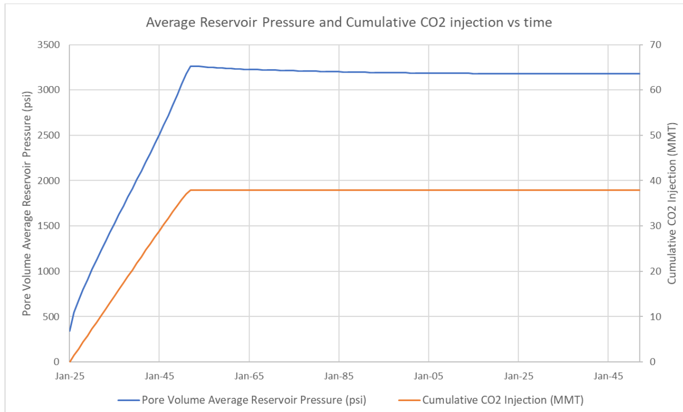
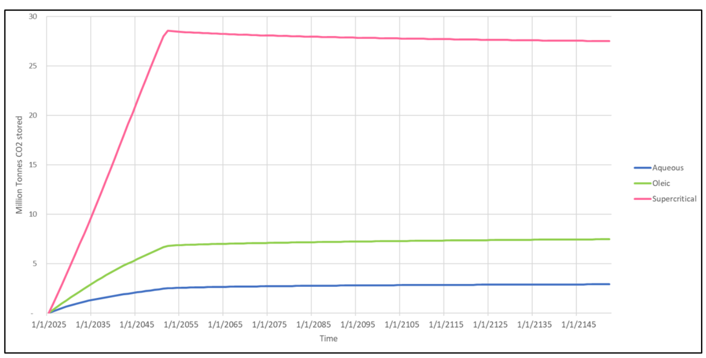


Figure 12: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 13 shows the cumulative storage for each of the mechanisms.

Figure 13: Storage mechanism through time for the 26R reservoir.



CO_2 Injectate Composition effect on Plume and AoR modeling

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.

The CO2 plume for Injectate 1 and Injectate 2 (detailed in the "Proposed Carbon Dioxide stream" section in this document) is consistent with the plume outline for 100% CO2 injectate (Figure 14), which was defined by a 0.03 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 14. The wells that fall within the CO2 plume are the same for all 3 cases.

Additionally, the average Pore Volume pressure was plotted for the 3 cases and there was minimal difference seen between the cases, as shown in Figure 15.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling. In addition, the AoR will be reviewed as per the Reevaluation Schedule and Criteria section.

Figure 14: CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Green) and 100% CO2 Cases (Red). Larger Red outline is the model boundary. There are Minimal difference in AoR boundaries between the 3 cases

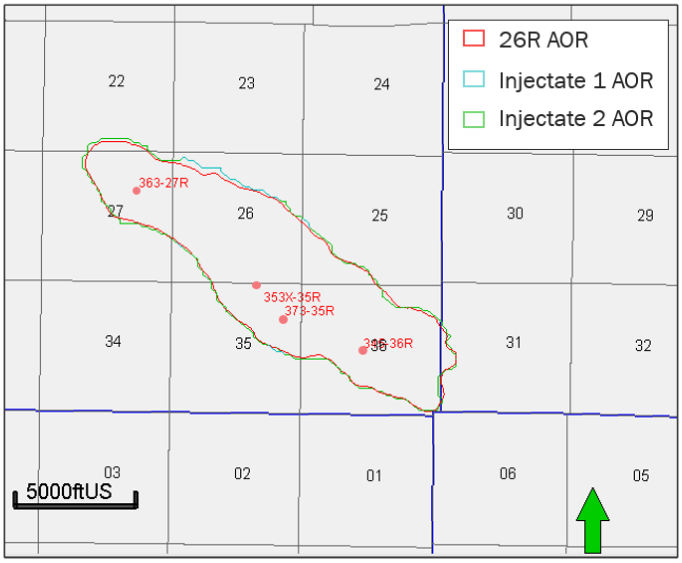
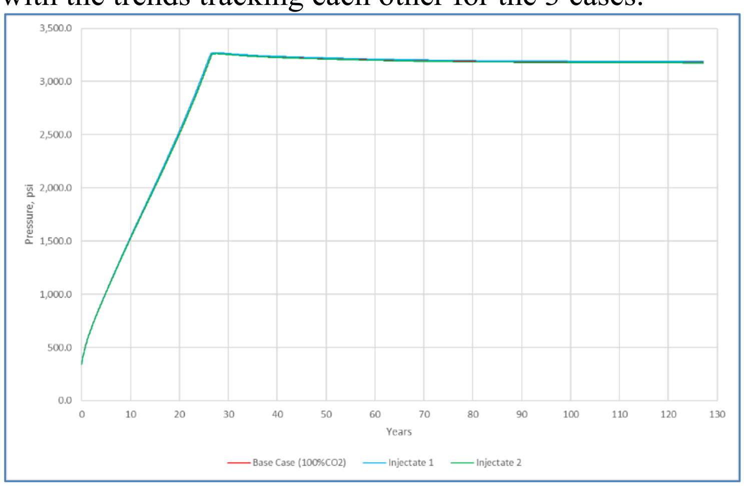


Figure 15: Average reservoir pressure vs time for Injectate 1 (Light blue), Injectate 2 (Green) and base 100% CO2 (Red) cases. Minimal difference in pressure trends between the 3 cases as shown in the graph with the trends tracking each other for the 3 cases.



Model Calibration and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

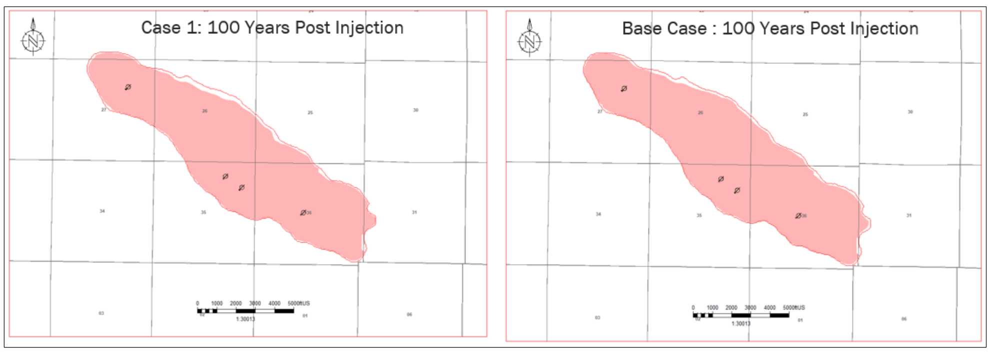
Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO_2 storage for the different cases, there was minimal change to the maximum extent of the CO_2 plume.

Table 10 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 16 compares the CO2 plume extent for Case 1 against the Base Case.

Table 10: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR

Figure 16: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.



These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

AoR Delineation

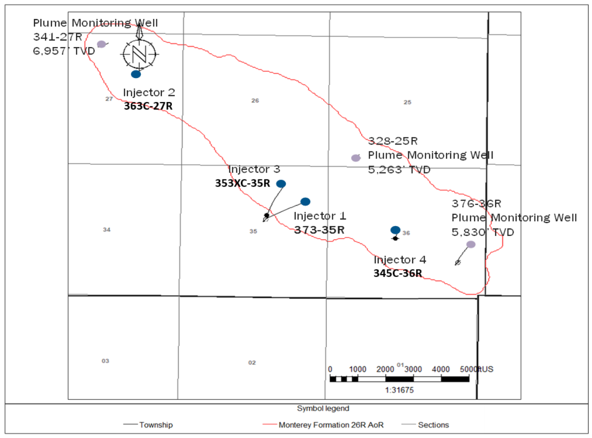
The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.
Figure 17 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 17: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

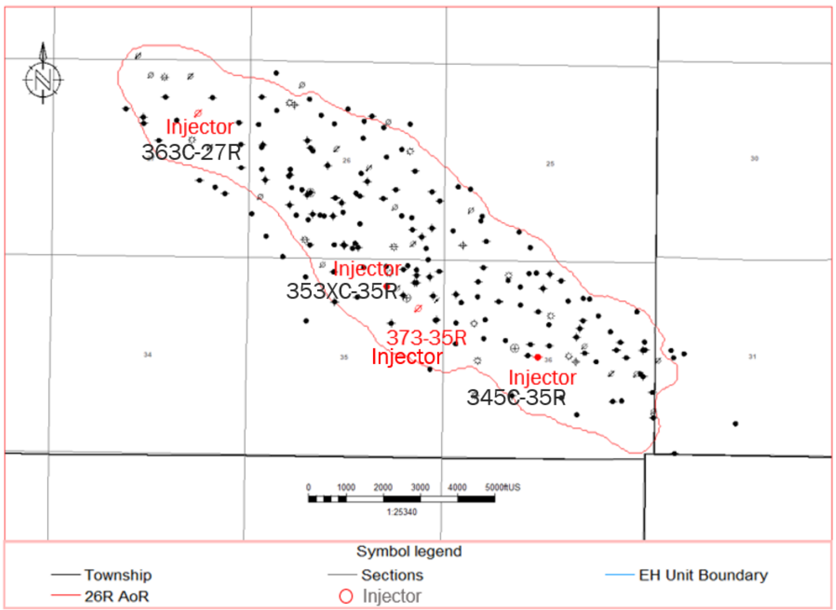
Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 11 is a summary of the AoR wells by type. Figure 18 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 11: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 18: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the "wellhead" level using API-10 and at the "wellbore" level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 12), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 12: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.

    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a deviation greater than +-10% from the Base Case.

    c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event.